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Characterizing and Predicting Short Term Performance for the In Salah Krechba Field CCS Joint Industry Project

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Abstract

In 2006, the CO2ReMoVe project funded by the European Commission was launched with the objectives of developing new and common methodologies and technologies to improve site based R&D for the monitoring, measurement and verification of the injection and storage of CO_2 at multiple sites. The In Salah Gas Krechba Field Joint Industry Project has been in operation since 2004 when gas from several fields was put on production. To comply with export regulations, the high content of carbon dioxide (CO_2), 1-10% in the produced gas is removed and re-injected down dip from the producing gas horizon, through three horizontal injection wells at approximately 1800 m below surface. Within the framework of CO2ReMoVe, this paper discusses the site characterization and the short term system performance for the In Salah Krechba field.

Prior to the injection, the reservoir unit and the seals were characterized. The resulting geological (static) model is consistent with the information obtained from the drilling activities in 2004 and 2005 and from the reprocessed 3D seismic done by Compagnie Générale de Géophysique (CGG) in 2006. A fracture study carried out on information obtained from resistivity and acoustic images available on the Krechba field had shown the existence of an open fracture network oriented along the NE-SW direction parallel to the maximum stress direction.

Typically, monitoring data serves as a calibration yardstick for the static model. It was therefore valuable information to detect the CO_2 breakthrough at KB-5, a suspended well located 1.7 km away from the KB-502 injector well. Tracer analysis confirmed the CO_2 detected at KB-5 came from KB-502. A multi-phase, multi-component compositional simulator specially designed for CO_2 sequestration (ECLIPSE[1] 300 with the CO2SOL option) was used to simulate and predict the properties of the injected carbon dioxide as well as that of the gas in place (mainly methane) and of the saline aquifer. History matching was used to calibrate the dynamic model by iteratively modifying parameters until a satisfactory match between model results and field measurements was obtained. The resulting dynamic model is used for short term predictions of the behaviour of injected CO_2. The history matching parameters are the fracture porosity, permeability and matrix permeability (difficult to measure permeability in a fractured medium). In each iteration, the simulated bottomhole pressures, gas (CO_2) injection rates were compared against field data as well as the CO_2 breakthrough time at KB-5. Iterations were repeated until a good match was obtained.

Predictive simulation results indicate that CO_2 would reach the northern part of the gas field in 2010 and would spread out over an area including production wells in 2015, both in the northern (KB-502, KB-503) and the eastern part (KB-501) of the gas field.

Although a good match has been obtained in the history matching process, some observed discrepancies could still not be explained only by fluid dynamics. Possibly, the application of coupled fluid flow and geomechanical simulations would aid in explaining the remaining discrepancies.

Keywords: In Salah; CO_2 storage; simulation; history matching; prediction

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INTRODUCTION

Geological sequestration provides a way to avoid CO_2 emission to the atmosphere, by capturing CO_2 from the source, transporting it and injecting it into deep underground formations. In Salah Gas (ISG) is a Joint Venture (JV) Project between BP (33%), Sonatrach (35%) and Statoil (32%), which comprises seven gas fields located in the Central Algerian Sahara. The carbon dioxide content in the natural gas produced from the In Salah project ranges between 1 to 10%, which is above the export (market) gas specifications of 0.3% and therefore require CO_2 removal facilities. Rather than venting CO_2, ISG compresses and re-injects the produced CO_2 stream (up to 70 MMscf/d or 1.2 million tonnes per year) back into the underground at 1,800 meters depth, within the water leg of the gas reservoir. The total predicted injected mass over the life time of the field will be 17 million tonnes. The re-injection of CO_2 from the produced gas stream is expected to result in a net emissions reduction of ~ 900,000 tones per year of CO_2 [1, 2].

Natural gas production and CO_2 re-injection started in August 2004 through three horizontal production wells (KB-11, KB-12 and KB-13) and two CO_2 injection wells (KB-501 and KB-503), respectively. In April 2005, two more wells were activated for production and injection; KB-14 and KB-502, respectively. The storage scheme has CO_2 re-injected directed into the aquifer portion of the Carboniferous reservoir, downdip of the main hydrocarbon accumulation. In July 2007, KB-502 was shut in after a CO_2 breakthrough was detected at a nearby old appraisal well (KB-5) suspended by Total in 1980 and being used as an observation well. KB-5 is now fully decommissioned.

FIELD GEOLOGY

The Krechba field is a low dip anticline of approximately 130 km^2. The Carboniferous and Devonian sandstones that make up the reservoir have been charged by Devonian and Silurian source rocks. The Carboniferous (Tournasian C10) reservoir lies at a depth of ca. 1800m below surface. It's mainly made up of good quality sandstones deposited in an estuarine setting. The reservoir is best developed (ca. 20m pay) in the northern and central parts of the field. To the east there were no wells at the time of seismic survey, so the seismic response in this area was less well constrained and therefore carries greater uncertainty. These Carboniferous sandstone reservoirs overlie the calcareous shale facies of the Upper Devonian and underlie 905m thick Carboniferous mudstones (mainly clays) that seal the gas trap. Those mudstones are overlain by approximately 900m thick Cretaceous sandstone and mudstone (Figure 1).

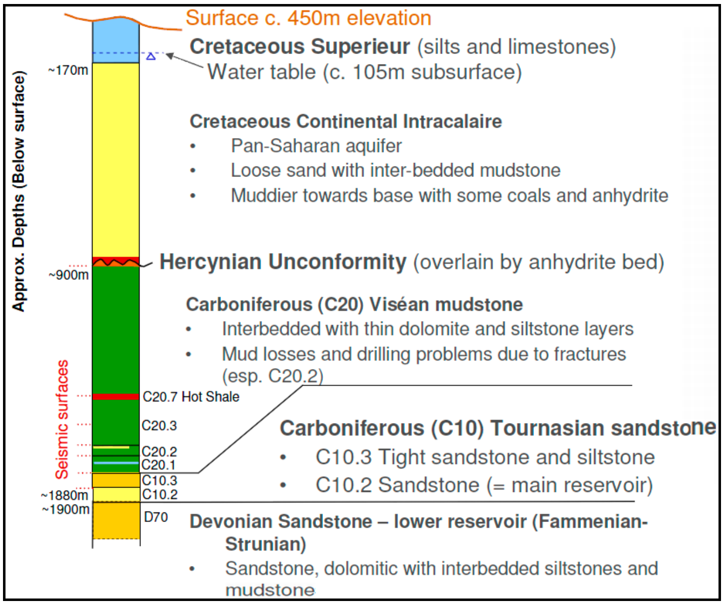

Figure 1 Krechba stratigraphic column, Courtesy of In Salah Gas Joint Venture

STATIC EARTH MODEL

A fracture study carried out on information from resistivity and acoustic images available on the Krechba field shows the existence of an open fracture network oriented along the NE-SW direction parallel to the maximum stress. Fullbore Formation MicroImager (FMI)[1] data covers the C10 horizons up to ~ -1,000 m TVDSS. Each zone of static model is

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thus crossed only once by the FMI data. Under these circumstances, for modeling purposes, the fracture intensity found at the well level was extended uniformly throughout the whole grid. This implies that fracturing at the well scale is considered to be the same as that at reservoir scale. Although an imprecise approach, since the fracture density can and may vary from one area to another, no other data exists to further describe the natural fracture network.

A study of the depth migrated reprocessed 3D seismic data shows the field to be faulted. A total of eleven (10) faults has been identified in C10 and these are included in the static model. All are of the reverse type. The longest fault measures nearly 9 km and the shortest is ~1 km long. The fault's throws range from 10 m to 40 m. The fault network has not yet been taken into account into the in the dynamic model, as there are not enough data to characterize their behaviour.

The porosity of the rock matrix of the reservoir was populated with the available log data. A Stochastic Sequential Gaussian algorithm was used as a geostatistical modeling tool to interpolate the data between wells and over the model domain, since the data were not dense enough for a deterministic approach. Matrix permeability data of the reservoir section was generated by a relation between porosity and liquid permeability acquired from core data. Table 1 summarizes the relations between porosity and permeability for the different zones of the reservoir, where ϕ is the porosity obtained from the static model at each grid point. The vertical to horizontal permeability ratio was assumed to be 0.1.

Table 1 Relations between core porosity and permeability for Krechba cored wells, Courtesy of In Salah Gas Joint Venture

Zone	Porosity to liquid permeability relation
Gas-zone	$k = 10^{-1.93375+15.6609*ø}$
Aquifer-zone excluding KB-501	$k = 10^{-2.22211+16.1922*ø}$
KB-501 area	$k = 10^{-5.16918+31.3430*ø}$

Modeling the fractured part of the reservoir was done through using a Discrete Fracture Network (DFN) model based on the fracture intensity as found from the resistivity images (FMI). Upscaling of properties based on the DFN model generated a second set of properties for the fractures: permeability, porosity and a sigma factor. The sigma factor is essential for connecting 'duplicate' cells in a simulator that describe the matrix as well as fracture porosity and permeability. Sensitivity studies have been carried out on the DFN parameters through matching a computed fracture intensity generated from the DFN modeling against that of the FMI data. The fracture's permeability is described through an empirical equation that relates rock fractures to fluid flow [4]. Fracture apertures were estimated from image log data.

$$K_{fracture} = 0.5 \times 10^{12} \text{ (Fracture Aperture)}^2/12 \ , \quad (1)$$

where $K_{fracture}$ is in darcy and aperture in meter.

DYNAMIC SIMULATION MODEL

The In Salah (Krechba) simulation model used for this study is a corner point geometry model with 76x40x2 grid points in x, y, and z directions, respectively. It covers an area of ~ 28 km x 18 km. The grid cell size along the X and Y directions are 370 m and 450 m, respectively. Within the C10 horizons, the average vertical grid size is around 20 m. The reservoir horizon C10 contains two distinct layers (C10.2 and C10.3) and each layer of C10 was divided into 3 sub-layers to better describe the vertical movement of CO_2. The total number of grid cells thus, is 76x40x6=18,240. A dual-porosity, dual-permeability model takes into account both the presence of the matrix and fractures. Since the fracture and matrix properties are not known at all points of the reservoir, the system is approximated by an orthogonal array of matrix blocks delimited by fractures, also called a sugar cube model.

No-flow boundary conditions were imposed at the top and bottom of the reservoir, i.e. no flow to overburden and underburden is allowed, as the objective of the short term simulation studies was to focus on the reservoir. No-flow boundaries are also imposed along the eastern and southern boundaries. Along the north and west boundary of the aquifer, the pore volume of the outermost cells was multiplied by a factor of ten which ensures that CO_2 that reaches the boundaries can flow out. The exact nature of the boundaries is unknown, therefore geologically more meaningful conditions cannot be imposed. (Figure 2).

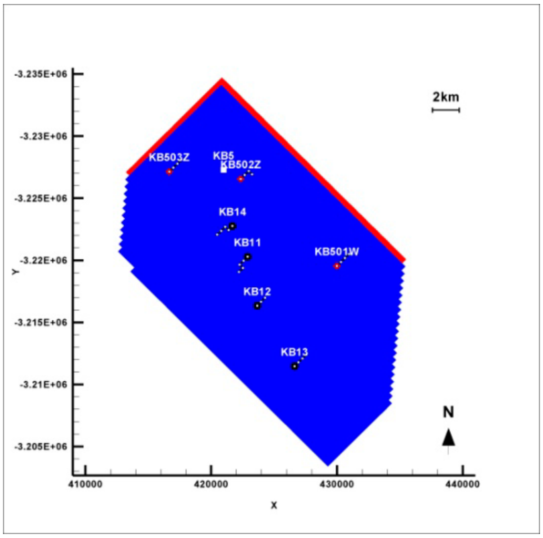

Figure 2 Modification of north and west boundaries: the red cells show where the pore volume multiplier was applied, color lines piercing the model represent the well's location. Injection wells: KB-501, KB-502, KB-503; Production wells: KB-11, KB-12, KB-13, KB-14; Abandoned well: KB-5.

Equilibrium initialization was used to calculate the initial fluid saturations and pressure distribution referenced to an initial pressure of 175 bars (~2540 psi) at the datum level of 1330 m (subsea). Initial reservoir pressure was interpreted from Krechba Carboniferous DST/RFT/MDT[2] formation pressure analysis. A DST interpretation shows the reservoir temperature to be 90 °C at the datum level. The simulations were run isothermal, meaning that fluid properties (density, viscosity) are only pressure dependent. A brine salinity of 170 g/l was used for the simulation to account for the solubility of CO_2 in brine. A four component (CO_2, N2C1, C2, C3-4) reservoir hydrocarbon fluid was used as input to the compositional simulation.

In a CO_2 injection and gas production process, as for all multi-phase flow processes, relative permeability is an important parameter since it determines the mobility ratio and the injectivity or production rate of the CO_2 and gas, therefore the effectiveness of the injection, storage and production process. For dual porosity-dual permeability models, two sets of data are needed: one set for the matrix medium, and another for the fracture medium. In the absence of core measurements specific to the fracture medium, it is generally assumed that the measured saturation functions represent the matrix, whereas the relative permeability curve for a fracture is assumed to be linear and the fracture capillary pressure is neglected [3]. Hysteresis has been considered of significance between the drainage and imbibition processes in the matrix. In CO_2 sequestration projects, the injection period is a drainage process, where CO_2 displaces water. After injection ceases, imbibition takes place; some of the brine previously displaced now migrates back and displaces the CO_2. The impact of such behavior is important for residual gas (CO_2) trapping. Due to lack of experimental relative permeability data, only hysteresis on capillary pressure was considered in this study. Water and gas relative permeability values and capillary pressure data for drainage and imbibition are given in Table 2. The irreducible water saturation is equal to 30% and the critical gas saturation is equal to 8%.

Table 2 Relative Permeability Values and Capillary Pressure Data, Courtesy of In Salah Gas Joint Venture

Sw	**Krw**	**Krg**	**Pc, drainage(bars)**	**Pc, imbibition(bars)**
0.3	0	1	10	10
0.38	0.000152	0.484797	2.53	1.7
0.46	0.002439	0.269314	1.84	1.14
0.53	0.012346	0.140566	1.49	0.78
0.61	0.039018	0.064892	1.26	0
0.69	0.09526	0.024131	1.09	0
0.77	0.197531	0.005831	0.93	0
0.84	0.36595	0.000407	0.78	0
0.92	0.624295	0	0.6	0
1	1	0	0	0

[2] DST (drill-stem test); RFT (Repeat Formation Tester); MDT (Modular Formation Dynamics Tester)

THE HISTORY MATCH PROCESS AND RESULTS OF PREDICTIVE DYNAMIC SIMULATION

Within this study, the following iterative procedure for the history matching (model calibration) was carried out: i) select the history matching parameters, typically those with the highest degree of uncertainty, ii) determine reasonable limits for the selected history matching parameters, iii) run and compare the simulated well and reservoir performance with the historical data, iv) change parameters, v) repeat the simulation with the adjusted model, then repeat steps iii) to v) until a good match was obtained between the simulated and observed production/injection and pressure data.

Classical history matching procedure was used whereby reservoir parameters are adjusted manually by trial-and-error. The input values to the simulation runs are the production/injection rate, well head pressures, along with known reservoir parameters (reservoir temperature, initial reservoir pressure, gas water contact, reservoir and aquifer fluid properties). Parameters that are optimized in most history matching techniques are primarily permeability, porosity, and other flow-related parameters. Similarly, for the In Salah project, matrix permeability, fracture porosity and permeability were chosen as history matching parameters since these parameters have the highest degree of uncertainty. Due to the presence of fractures in the field, the measured matrix permeability is questionable; it is difficult to take unfractured samples from fractured cores. Furthermore, the core measurements were conducted at 400 psi confining pressure, a value much lower than that of the overburden pressure. Measured core permeability is probably overestimated. Unfortunately, no measurements exist under different confining stresses to be able to describe the reservoir behavior under increasing overburden stresses. Fracture properties, were derived from an empirical equation given above, calibrated against known data.

The objective of this history matching exercise was to obtain an adequate match of downhole pressures for each well, as well as the CO_2 breakthrough time at KB-5. In June 2007, KB-502 was shut in after a CO_2 breakthrough was detected at KB-5, a nearby old appraisal well being used as an observation well. The exact time at which the CO_2 plume reached KB-5 is unknown, since monitoring measurements are done yearly, the last measurement before the CO_2 breakthrough being in August 2006. Thus, the matching objective for the breakthrough time was qualitative; i.e. anytime between August 2006 and June 2007 was thought to be acceptable. Therefore in the matching procedure, the priority was given to downhole pressure. At the end of history matching, the average fracture permeability and matrix permeability in the main reservoir (C10.2) are 2.5-7 mD and 0.5 mD, respectively. Relatively low permeability was obtained for C10.3, which is coherent with the formation characteristics since C10.3 is much tighter (having lower porosity) than C10.2. Average fracture porosity of 0.7-1% is obtained after history matching. Adjusting and changing each parameter through a trial and error on the ranges given in Table 3 resulted in some 100 combination runs. The sensitivity ranges tabulated are the ranges in which each parameter was adjusted.

Table 3 Average C10.2 (Matrix & Fracture) Parameters Before and After History Matching

	Parameter	**Initial Values(from Static model)**	**Sensitivity Ranges**	**Final Values (after History matching)**
Matrix (Field Average values)	**Porosity**	14-20 %	–	14-20 %
	PERMX, mD	6-8	0.01-10	0.5
	PERMY, mD	6-8		0.7
	PERMZ, mD	0.8		0.07
Fracture (Field Average values)	**Porosity**	0.01%	0.01 to 1%	0.7%
	PERMX, mD	70	0.01-250	2
	PERMY, mD	240		7.5
	PERMZ, mD	240		0.02

Generally, the match was obtained by reducing overall the permeability: matrix permeability was reduced by about an order of magnitude while the fracture permeability was reduced by even up to several orders of magnitude. Additionally, the resulting fractured part of the model was made more anisotropic: vertical permeability was reduced more drastically than lateral permeability.

Figure 3 shows the gas (CO_2 as well as natural gas) saturation, in top view, at different times. Gas saturation around the production wells delineates the location of the gas field, while gas saturation around injectors refers to CO_2. CO_2 breakthrough at KB-5 occurred roughly 20 months after the start of CO_2 injection at KB-502, i.e. January 2007. Again, it should be noted that the breakthrough time was not certain and was only matched qualitatively for the reasons mentioned before. At the end of January 2008, which corresponds to the end of available historical data, the CO_2 gas saturation is about 0.6-0.8, near the injection wells in the model.

Figure 4 shows a fair match of the bottom hole pressure (BHPs) in the 3 injectors. Some discrepancy (for example between March, 2006 and Oct, 2006 in KB-503) could not be fully explained by fluid dynamics only. Due to the inherent difficulty of describing the fracture network with limited data and its large impact on total permeability, possibly further geomechanical study may help understand the discrepancies better.

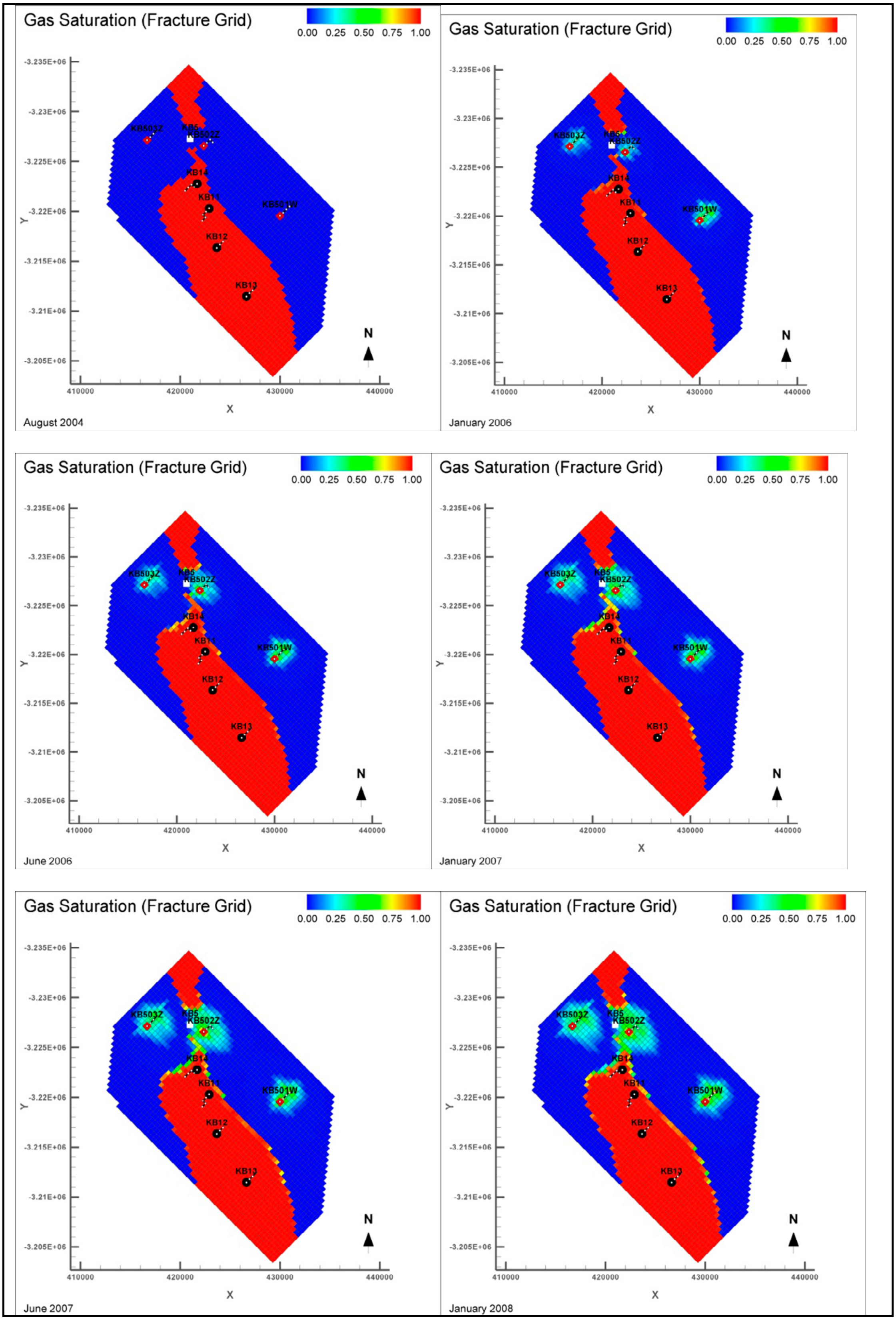

Figure 3 Gas saturation maps, in top view (C10.2), at different times (dates are on the left bottom corner of each figures)

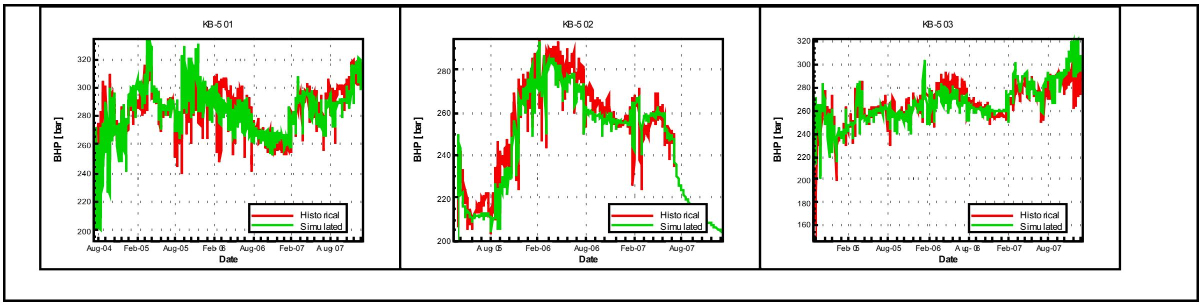

Figure 4 Bottom Hole Pressures (bar) at injection (KB-501, KB-502, KB-503) wells: measured (red) and simulated values (green).

SHORT TERM PREDICTION RUNS

Prediction simulation runs give the engineer a possibility to visualize the future performance of a well or a reservoir. In the In Salah project, a more detailed prediction study will be carried out during a later phase in the project for "long-term system performance analysis", but within the scope of the work described herein, only a prediction run until January, 2015 (~7 years after history matching period) was performed. The average injection and production rates were derived from past well performance. Due to the limited of information on KB-502 remedial plans and its possible re-use in the future, the prediction runs were done with only 2 injector wells: KB-501 and KB-503. Prediction results (Figure 5) indicate that CO_2 would reach the left edge of the model by 2010 and spreads out over an area including production wells by 2015. The main factor controlling the spread of CO_2 is the presence of fractures as flow paths. The shape of the CO_2 plume reflects also the fracture direction (NW-SE trending). It is evident from these results that any longer term forward models would need an extended model domain.

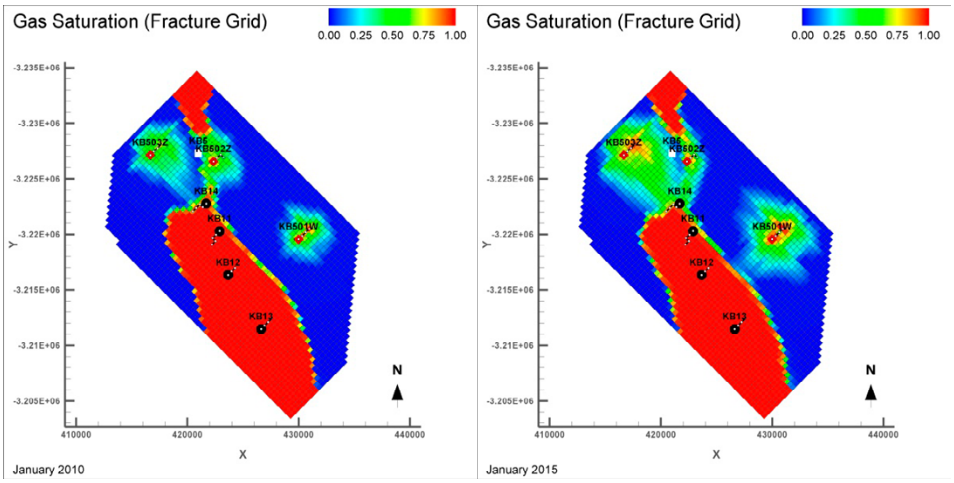

Figure 5 Prediction runs: gas saturation at reservoir level (C10.2) - January, 2010 (left) and January, 2015 (right)

CONCLUSIONS AND RECOMMENDATIONS

The multi-phase multi-component compositional ECLIPSE simulator has been used to model and to predict the short term (less than a decade) system performance of CO_2 injection in In-Salah. The detection of fractures in FMI logs in a single well has led to the application of a dual-porosity dual-permeability reservoir model using geostatistical algorithms to populate properties over the 3D domain, although with large degree of uncertainty. The size and field extent of fractures remain to verified when new data become available from future wells.

A injection history matching study was carried out to calibrate the static model through an iterative process by modifications of the matrix permeability, the fracture's porosity and permeability – i.e. parameters which have the largest uncertainty in the model. Good results have been obtained in matching the bottomhole pressure of each injection well as well as of the approximately known CO_2 breakthrough time at KB-5 for both the C10-2 and C10-3 reservoirs. At the end of history matching, the average fracture permeability and matrix permeability obtained were 2.5-7 mD and 0.5 mD, respectively in the main reservoir layer (C10.2). Permeability values were relatively lower for C10.3 reservoir, in accordance with the formation characteristics since C10.3 has lower porosity average porosity than the C10.2 reservoir. Overall the matched permeability is much lower than the initial model. This may be attributed to the difficulty in obtaining representative samples and permeability measurements in the laboratory for fractured rocks which may tend to overestimates.

The lateral movement of the CO_2 plume is dominated by the high ratio of horizontal to vertical permeability, with some of the CO_2 reaching the top of the C10.3 reservoir zone. Currently, the vertical extent of the fracturing system into the cap rock (overburden) and its geomechanical state are unknown. The potential for CO_2 migration into the cap rock will be addressed at a later phase with the long-term system performance analysis. A simulation prediction until January, 2015 (~7 years after the end of history matching period) was performed using the average production and injection schemes. This simulation suggests that injected CO_2 will reach some gas production wells by year 2015.

This simulation study should be checked against the soon to be acquired 3D seismic data, before any predictive scenarios for the long term performance can be carried out. It is clear from this exercise that the dynamic model boundaries need to be extended considerably for longer term scenarios. Although promising results (a good match) were obtained considering the high degree of uncertainty on reservoir parameters, some of the discrepancy between simulated and measured parameters could not be explained only by fluid dynamics. Possibly, the application of coupled fluid flow and geomechanical simulations would aid in explaining the remaining discrepancy.

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